Ofgem Locational Pricing Assessment – call for input

Background to ENGIE

ENGIE owns First Hydro in a 75/25 JV with Brookfield Renewable Partners. First Hydro comprises 2088MW of pumped hydro generation at two sites, Dinorwig (6 units each of 288MW capacity, 10.3GWh of storage capacity) by Llanberis and Ffestiniog (4 units each of 90MW capacity, 1.3GWh of storage by Blaenau Ffestiniog, both in North Wales.

ENGIE has a stake in Ocean Wind, a joint venture that secured a contract in AR2 to develop Moray East offshore windfarm off the coast of Inverness. This is now operational. It is hoping to secure a contract in AR4 for Moray West. ENGIE also owns around 50MW of onshore wind capacity / solar PV in GB.

ENGIE's retail business supplies I&C customers with electricity and gas.

Response to call for input questions

The key opportunities associated with introducing more granular locational pricing in GB;

This has the potential to reduce costs but other solutions need to also be explored that can also achieve this – for example, not paying renewable generators when the market price is below zero. This will happen from AR4 onwards for CfD generators and its extension to renewable generators supported by ROCs could be considered (and maybe to those with existing CfDs).

Whilst such a change will have implications for these type of generators, it avoids the need to also change the wholesale market arrangements and preserves liquidity at the national level. Whatever is done to address the need to overhaul the market design is going to be painful. The goal should be to have a market suitable for net zero that requires the least change and preserves investment signals.

The key implementation challenges, risks and mitigations

- Hiatus on investment whilst debating and then implementing the solution – this could be mitigated by grandfathering current rights (but this wouldn't solve the problem) or compensating proven losses. There will be winners as well, would any windfall from a new market design have to be considered?

- Impact on liquidity – FTRs will help here but would be a costly solution for flexible generators. This has a knock on effect on the need for and provision / cost of flexibility

- Potential to create a two / three tier market depending on how far locational pricing extends into the distribution network. The design could create a competitive advantage depending on where a network user is connected. ideally locational pricing should be market wide and include consumers to avoid this situation. We assume therefore that each generator and demand would be assigned to an upstream node/zone, so it would be also exposed to transmission locational prices. Demand should also be included in the locational pricing, to allow for demand response. Suppliers could adapt the tariffs for customers not willing to take the locational price risk, or the government could create its own regulated supplier to protect vulnerable customers.

The proposed approach to modelling zonal and nodal market designs

This needs to align with how far into the distribution network locational pricing extends. There is little point modelling transmission only nodes as proposed in the document, if the intention is to have fully nodal pricing down to the customer level. The modelling needs to cover the range of implementation options. Intuitively, there would be little point only introducing locational pricing at the transmission level only. The same locational signals should apply to demand.

Slide 30: Q: What are your views on how generation capacity should be forecasted?

Generation expansion planning could be obtained from an optimisation model, and the optimisation should consider both transmission and generation investment options. Given that the Transmission Owner (TO) has its own process to plan for network investments (NOAs), the generation expansion could be included in the same process and be compatible with the FES scenarios. A by-product of optimisation will be the congestion rent (TO's opportunity cost to invest), so this could lead to price signals that the TO could use to hedge the cost of expansion with generation companies hedging locational revenues.

There is a large academic literature with different modelling approaches, e.g. including equilibrium models, which ensure that generation companies have the incentive to invest. Otherwise, as is usual in LT models, it can be assumed that the optimisation solution will be guaranteed by the existence of competitive markets, such as a market for transmission rights.

The difficulty will be to set realistic limits on build potential by zone, reflecting local planning / connection constraints, for large thermal assets especially. The model results will also be highly sensitive to nuclear developments. It will be important to reflect the potential for redistribution of demand centres as well (not just DSR). Ofgem should seek views on returns required as investment discount rates will likely be higher than that assumed in the model.

Generation capacity build out may also be affected by uncertainty in compensation mechanisms. How (will?) the model take account of this?

35: Q: What are your views on our approach to modelling CFD contract holders?

For current CfD, contracts must be honoured, and the existing strike prices continued. This means that:

- the public company (LCCC) should compensate the additional volume/congestion risk faced by the generator, i.e. volume out-of-merit in the locational price, but in-merit in the national price index. For that, a form of deemed generation energy (FPN) should be used for the settlement in such cases, like is done in the current market setting; and

- The public counterparty should compensate the additional balancing risk faced by the generator, i.e. lower market liquidity to adjust forecast errors. For that, a parallel compensation mechanism could be design, for instance levelling the balancing cost with the equivalent national index.

For new CFD arrangements there are two possibilities which may be compatible:

- The public company takes the congestion risk, and publishes the forward congestion rent for each node and technology to be included in the CfD auction mechanism. The forward congestion rent could be provided by the TO, so this should net the investment risk in transmission, assuming that the TO is a public company; or

- The generation company takes the congestion risk, and adjusts the bidding price to reflect the expected revenue lost. This risk might be too high to secure the investment case of the participants.

The model must be exogenously assuming or endogenously building transmission capacity. Either way the model is assuming that new transmission and new offshore wind are coordinated and committed to. If transmission capacity is delayed, the risk of higher than anticipated congestion / price cannibalisation for a new wind site should not be borne entirely by the generator. There are two options:

- Share the risk with the Consumer via a Strike Price adjustment mechanism
- Share the cost with the TO via a congestion payment.

37: Q: What are your views on the potential impacts of locational pricing on the cost of capital?

The locational granularity in the market implies lower liquidity and higher volatility in the revenues, all of which increases substantially the market risk of market participants.

The increase in risk should be compensated by other forms of capacity payments, incentivising the investment of generation in the right place, or the successful introduction of a market for FTRs.

However traditional FTRs are not a good hedge for new flexibility technologies such as storage, and intermittent technologies such as wind and solar, as their market risks do not depend directly on the baseload profile.

The cost of capital will increase, potentially inhibiting the development in the remoter (but higher yield) sites in the UK. It should not be assumed that investments will happen in line with government targets as there is a point at which the UK become less appealing a market relative to others.

39: Q: What are your views on (1) our proposed sensitivities; (2) other sensitivities we should include; and (3) which one do you see as a high priority?

All sensitivities are equally important. A sensitivity with a significant delay to offshore wind development should also be included.

The total system costs (new market establishment + transmission build-out + renewables subsidies + energy and operational costs, impact on liquidity) should be presented for each scenario. The impact of an investment hiatus also need to be considered .

The total system cost should also be presented for alternative market designs without nodal/zonal pricing, such as the status quo or simpler alternatives, such as the separation of the dispatchable market from subsidised generation or not paying renewable generators when market prices are negative.

For further information, please contact

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